W&T OFFSHORE

Matterhorn TLP
Mississippi Canyon Block 243; Well A-5
OCS-G-19931 / API #60-817-40977-00

APPLICATION FOR PLUGBACK IN PREPARATION FOR SIDETRACK

WELL HISTORY

The Matterhorn field is located in the Gulf of Mexico @ Mississippi Canyon Block 243 (MC-243) in 2,816' of water, approximately 30 miles SE of the mouth of the Mississippi River and about 100 miles SE of New Orleans Louisiana.

The MC-243 A-5 was drilled by Total in the 2002 utilizing the semi-submersible "Ensco 7500". The well was TA'ed, and a floating TLP was installed @ the location. The platform rig "Nabors SSD 16" was mobilized for the completion operations. The A-5 was initially completed in 2004, as a single string selective installation, with sand control to the upper & lower lobes of the "A Sand". The A-5 well produced oil from the A-Sand, until a sand control failure in 2007 led to shut-in.

A coiled tubing unit was mobilized to location February 2011, and the well was cleaned out and returned to production. Production was intermittent thru 2012, as solids & emulsions from the A-Sand repeatedly disrupted processing facilities.

The A-5 will be converted into a water injector for pressure maintenance of the A-Sand. A coiled tubing unit was mobilized to location November 2012, and the A-Sand has been temporarily Plugged & Abandoned in preparation for a sidetrack. The Platform Rig "Nabors Super Sundowner #19" is on the Matterhorn platform for a drilling & completion program. The A-5 will be cleaned out, plugged back, and sidetracked. A new completion to the A-Sand is planned inside a 7" Liner.

OBJECTIVE

Successfully retrieve the production tubing and accessories from the A-5 wellbore, and plug-back the well in preparations for a sidetrack, while working safely and doing no harm to personnel, environment, or equipment.

CURRENT INTERVAL (Temp P&A'ed):

Reservoir Name & Type:	A-Sand
Produced Fluid:	Oil
Perforated Interval 1 (MD):	8533 - 8603' MD
Perforated Interval 1 (TVD):	6567 - 6599' TVD
Perforated Interval 2 (MD):	8833 - 8866' MD
Perforated Interval 2 (TVD):	6716 - 6735' TVD
Max Deviation:	70o @ 8000' MD
Deviation @ Zone:	63o
Reservoir Temperature:	110o F
Reservoir Pressure:	3200 psi / 9.1 ppg
Proposed Workover Fluid:	10.0 ppg CaCl2

MASP: (9.1 ppg – 4.4 ppg)*0.052*6735' =~ 1700 psi

NOTE: "A-Sand" was temporarily abandoned via coiled tubing November 2012. A cement plug was placed inside the Lower A-Sand Gravel Pack assembly @ 8540 - 8876' MD. The cement plug was tested to 1000 psi. A cement plug was placed in the tubing/casing annulus above the Upper A-Sand Gravel Pack assembly @ 8225 – 8285' MD. This plug was also tested to 1000 psi.

NOTE: The 4-1/2" Long-String tubing is full of 8.6 ppg FSW (field salt water). The 1.9" Short-String tubing above the POTH, and the 10-3/4" x 4-1/2" annulus below the POTH to the lowermost Gas Lift Mandrel @ ~5962' MD, should be dry due to gas lift. The 10-3/4" x 4-1/2" annulus below gas lift depth should contain 10.8 ppg CaCl2 completion fluid.

PRELIMINARY OPERATIONS:

1. Check and record pressure on all tubing and casing strings. Open the SCSSV. Monitor the well for 10 minutes.

2. RU slickline and lubricator on the 1.9" gas injection string (short string). Test lubricator to 3000 psi. RIH with GR/JB to A-1 Gas Lift Injection Valve @ ~3288'. POH.

3. RU pumping lines on the 1.9" tubing (short string), and pump 10.0 ppg CaCl2 down the 1.9" tubing, taking returns up the 4-1/2" tubing string. Fill the casing/tubing annulus below the POTH.

4. RU pumping lines on the 4-1/2" tubing (long string) and attempt to pump down the tubing. Pressure up to 1000 psi and monitor for 15 minutes. Note the pressure @ the surface and the pressure recorded on the downhole gauge. Bleed off pressure.

5. RU slickline and lubricator on the 4-1/2" tubing (long string). Test lubricator to 3000 psi. RIH with GR/JB, to ~ 6900' MD. POH.

6. RU Electric Line and lubricator on the 4-1/2" tubing (long string). Test lubricator to 3000 psi. RIH with GR/CCL to ~ 6550' MD, and log the 4-1/2" tubing up through the Mudline Hanger Packer, to ~ 3000' MD. POH.

7. RIH w/ 4-1/2" Thru-Tubing Bridge Plug, and set same in middle of a full joint @ ~ 6500' MD'. POH.

8. RU pumping lines on the 4-1/2" tubing (long string) and pressure up to 1000 psi and monitor for 15 minutes. Note the pressure @ the surface and the pressure recorded on the downhole gauge. Bleed off pressure.

9. Fill the casing/riser with 10.0 ppg CaCl2. Monitor the well for 30 minutes.

ND TREE / NU BOP's:

10. Close the SCSSV. Install a 4" Type H BPV in the 4-1/2" Tubing Hanger and a 1-3/4" BPV in the 1.9" Tubing Hanger. ND the FMC Tree. Install 4-1/2" & 2" Blanking Plugs, respectively, over the Hanger/BPV's.

11. NU 11" 5M x 11" 5M flanged riser section.

12. NU 11" x 10M BOP stack. Rams will contain 5" x 2-7/8" VBR's in the upper & lower chambers. Test Annular to 250/3000 psi, and VBRs to 250/5000 psi. Test against 4-1/2" pipe body.

NOTE: Requesting approval to test BOP assembly to less than maximum rated pressure of the equipment. The maximum working pressure of the pipe and the blind/shear rams is 10,000 psi and the annular is 5000 psi. However, the expected maximum wellhead pressure during workover operations is 1700 psi.

PULL TUBING:

13. MU blanking plug retrieving tool(s) to landing joint and retrieve 4-1/2" & 2" Blanking Plugs, respectively.

14. MU BPV retrieving tool(s) to landing joint and retrieve 4" & 1-3/4" BPV's, respectively.

15. Make up the FMC Tubing Hanger Running and Retrieving Tool to the landing joint. RIH and engage tubing hanger.

16. Open the SCSSV. Rig up slickline and lubricator on the 4-1/2" long string. Test lubricator to 3000 psi.

17. MU and RIH with tubing punch, and punch hole in punch nipple @ 3322' MD, immediately below the POTH (Baker Pack-Off Tubing Hanger).

18. Apply 5000 psi down the 4-1/2" tubing to release the POTH. Bleed off pressure.

19. Rig up Electric Line and lubricator on the 4-1/2" long string. Test lubricator to 3000 psi. RIH with cutter for 4-1/2" tubing. Position the cutter @ ~ 6470' MD (middle of first full joint immediately above the TTBP), cut the tubing, and POH with cutter. Attempt to circulate to confirm cut. Repeat if necessary.

20. Pull tubing to free the POTH and surface tubing hanger. Once the tubing string is free, pump 10.0 ppg CaCl2 down the 4-1/2" tubing, up the riser, to fill the wellbore. Monitor well.

21. POH, laying down the production equipment.

22. Pick up 4-1/2" 16.6# S-135 XH (NC-46) workstring. MU and TIH with scraper assembly for 10-3/4" & 9-5/8" Casing. Tag top-of-fish (cut tubing @ 6470'). Circulate to displace the well from 10.0 ppg CaCl2 to 10.5 ppg WBM. POH.

23. MU and TIH with 9-5/8" 53.5# Cast Iron Bridge Plug and Setting Tool. Tag top-of-fish and PU ~ 20'. Set CIBP @ ~ 6450' MD, immediately above the cut tubing, and release from same. Test CIBP to 1000 psi for 10 minutes.

24. Establish circulation down the tubing, taking returns up the annulus. Continue pumping while spotting an 14 bbl (80 ft^3) cement plug @ ~ 6250 - 6450' MD.

25. PU above cement and circulate clean. WOC. Test plug to 1000 psi for 30 minute and chart same. Bleed off pressure and monitor well. When well is stable, slack off and tag TOC. POH.

26. Transfer to Application for Sidetrack at this time.

WELL SHUT-IN PROCEDURES WHEN PULLING DUAL COMPLETION WITHOUT DUAL RAMS.

- The wellbore will be mechanically isolated from the hydrocarbon zone(s) via a cement plug in the lower completion assembly, a packer and seal assembly, and a X-Plug in the Nipple Profile @ 8181'. These barriers will have been tested.
- The well will not have pressure on it, as it will be full of kill weight completion fluid.
- The Dual Completion String that is above the Mudline Hanger Packer consists of a 1.9" gas lift line and 4-1/2" 13Cr 12.75# BTS-8 production tubing with 8 control lines.
- Due to the number of control lines present while removing the dual completion, it will render the use of dual rams in the BOP's ineffective. Therefore, based on 250.615 (b) (c) a variance will be requested from the BSEE not to use these dual rams in the completion of the well.
- Prior to running the dual strings, a kill stand will be made up and placed in the V-Door for immediate access. This stand will consist of 4-1/2" 13Cr 12.75# BTS-8 production tubing and a tested full opening safety valve.
- A control line cutter will be maintained on the rig floor at all times, to severe any lines that may potentially obstruct the ram closing.
- The following procedures will have to be followed in case of wellbore instability:

DUAL STRING COMPLETION SHUT-IN PROCEDURE:

1. Close the Annular Preventer around the dual tubing strings to restrict or minimize flow while PU the kill stand.
2. Make up the kill stand to the existing production tubing.
3. Fill up the well through kill line at a maximum rate.
4. Cut and secure the control lines that may interfere with closure.
5. Secure the last joint of 1.9" tubing to the 4-1/2" production tubing with tape, tie-wraps, or clamp.
6. Open the Annular Preventer. Lower the kill stand across the BOP and close the Annular Preventer around the kill stand.

- Based on the well control situation the influx will be handled as follows:
    - Circulated out on a standard drillers method will kill operation.
    - Volumetric lubricate and bleed method, if circulation is not possible.
    - Bullhead formation fluids back into the formation with heavy fluid.
    - In a severe well control event the completion will be sheared and dropped to bottom.